TECHNICAL REVIEW AND EVALUATION
CAITHNESS BIG SANDY, L.L.C.
AIR QUALITY PERMIT NO. 1001532

I. INTRODUCTION

This Class I (Title V) Permit is for the installation and operation of the Big Sandy Energy power plant (Big Sandy), which will be located approximately 40 miles southeast of Kingman, along U.S. Highway 93 near Wikieup, in Mohave County, Arizona. This is a new “merchant” power plant project that will generate and sell electricity produced by natural gas combustion. The applicant originally submitted its permit application in February 2001. A revised permit application was submitted in October 2001, which included numerous data submittals provided to the Arizona Department of Environmental Quality (ADEQ) to clarify the original permit application.

A. Company Information

Facility Name: Caithness Big Sandy, L.L.C.

Mailing Address: The Grace Building
1114 Avenue of the Americas
New York, NY 10036

B. Attainment Classification

The proposed source is to be located in an area that is designated attainment/unclassified for all criteria pollutants: total suspended particulate (TSP), particulate matter less than 10 microns in diameter (PM_{10}), nitrogen dioxide (NO_2), sulfur dioxide (SO_2), carbon monoxide (CO), lead (Pb), and ozone (O_3).

II. PROCESS DESCRIPTION

The Big Sandy Project is a natural gas fired combined cycle merchant power plant with a total site rating of 720 Megawatt (MW) (nominal). The facility is to be constructed in two stages, with the first stage being a 2 on 1 configuration with a rating of 500 MW (nominal). The first stage will consist of two combustion turbine generators (CTG), two heat recovery steam generators (HRSG), one steam turbine generator (STG), and one mechanical draft cooling tower. The second stage will be a 1 on 1 configuration with a rating of 220 MW (nominal), which will consist of an additional combustion turbine, HRSG, STG, and mechanical draft cooling tower. The initial and revised permit applications present emissions and modeling analyses for both stages combined. Only natural gas fuel will be used for the combined cycle units. Due to the staged nature of the project, a permit condition has been included stating that construction must begin no later than 18 months after permit issuance and that there cannot be more than an 18 month lapse in construction activities between the stages, or the permit will be terminated.

The project is classified as Standard Industrial Classification Code 4911 and North American Industrial Classification System 221112, Fossil-Fuel Electric Power Generation. The primary processes at this facility consist of the following equipment:

- Three (3) Siemens V84.3A CTGs equipped with dry low-nitrogen oxide (low-NO_x) combustors - two in Stage I and one in Stage II;
- Three (3) HRSGs with supplemental duct firing at a rated heat capacity of 103 million British Thermal Units per hour (MMBtu/hr) (higher heating value (HHV)) - two in Stage I and one in Stage II;
- Two (2) STG units - one in Stage I and one in Stage II;
- Three (3) selective catalytic reduction (SCR) systems for controlling nitrogen oxide (NO_x) - two associated with the CTG/HRSGs of Stage I and one associated with the CTG/HRSG of Stage II; and
- Three (3) oxidation catalyst systems for controlling CO and volatile organic compounds (VOCs) - two associated with the CTG/HRSGs of Stage I and one associated with the CTG/HRSG of Stage II.

The support processes at this facility will consist of the following equipment:

- One (1) 8-cell wet mechanical draft cooling tower equipped with high efficiency drift eliminators for the Stage I steam turbine condenser and equipment cooling;
- One (1) 4-cell wet mechanical draft cooling tower equipped with high efficiency drift eliminators for the Stage II steam turbine condenser and equipment cooling;
- One (1) diesel-fueled emergency generator, 1,341 horsepower (hp);
- One (1) diesel-fueled engine to drive the emergency fire water pump, 1,341 hp;
- Main transformers; and
- Other ancillary equipment.

A process flow diagram of the Big Sandy project is presented in Figure 1. The combustion turbine compresses chilled air which is mixed with natural gas and burned in the dry low-NO_x combustors. The resulting high temperature gases pass through the power turbine and exhaust to the HRSGs. The power turbine drives both the compressor and an electrical generator. The generators on each CTG are capable of producing 180 MW (International Standards Organization (ISO) conditions). The turbine exhaust gases are treated with an SCR system and an oxidation catalyst to further control NO_x, CO, and VOC emissions before being exhausted to the atmosphere.

Figure 1. Big Sandy Process Flow Diagram

The HRSGs are boilers that generate steam from the heat in the CTG exhaust gases. To increase overall output from the facility, supplemental (duct) firing of the HRSGs using natural gas may be performed so that additional steam can be produced for the STG. The STGs are capable of generating 120 MW each. Because the STGs do not combust fuel, there are no air emissions from these units.

Low pressure, low temperature steam exhausted from the STG is condensed in the main condenser. The condensate is recycled for use in generating more steam. The condenser is cooled by the circulating water system that rejects waste heat to the atmosphere by evaporation in the cooling towers.

III. EMISSIONS

Tables 1 through 4 present the proposed short-term and annual emission limits for the units. The proposed permit limits are based on vendor and applicant data, and the application of control devices selected through the BACT analysis.

A. Normal Operations - Hourly Emission Rates

Table 1 lists the combined cycle unit maximum hourly emission rates under any combination of full load operation and ambient temperatures. Table 1 also includes emissions with duct firing, which is to occur only after a combustion turbine has reached 100 percent load.

Table 1. Hourly Emission Limits During Periods Other than Start-up or Shutdown

Device	Hourly Emissions, Each CTG/HRSG, pound per hour (lb/hr)				
	NO_x	CO	VOC	PM_{10}	SO_2
Combined Cycle Systems	17.0	8.0 7.75*	2.75 3.45*	16.5 18.0*	3.1

* Emission limit with duct burner firing.

Notes:

1. The Combined Cycle System consists of one combustion turbine, one heat recovery steam generator with its associated duct burner, post combustion emission control systems, and exhaust stack.
2. PM_{10} emission rate includes condensible and filterable components.
3. Normal operation for the turbines are defined as loads above or equal to 75% of nameplate capacity, and start-up/shutdown are defined as loads below 75% of nameplate capacity.
4. Duct burning is limited to 4,000 hours per year for each Combined Cycle System.

B. Start-up/Shutdown Operations - Hourly Emission Rates

Emissions of NO_x, CO, and VOCs from the combustion turbines during start-up/shutdown are significantly higher than during steady-state, full load operation. This is because combustion temperatures and pressures are rapidly changing during start-up/shutdown (which results in less efficient combustion and higher emissions), and because the dry low-NO_x combustors are operating in diffusion mode, not dry low-NO_x mode. In addition, pollution control systems such as oxidation catalysts are not as effective during the transitory temperature changes that occur during start-up /shutdown.

The higher NO_x, CO, and VOC start-up/shutdown emission rates must be included in the annual potential to emit (PTE) calculations, and are also considered in the air quality modeling analyses. The only pollutant that requires a separate start-up/shutdown short-term modeling analysis is CO, because it is the only one of these three pollutants with short-term air quality standards. For NO_x, the air quality standard is an annual standard, therefore the annual NO_x emission rate that is modeled must include total emissions from both normal operations and start-up/shutdown operations. Because of the CO and NO_x modeling requirements to demonstrate compliance with air quality standards and increments, separate start-up/shutdown emission limits have been established for CO and NO_x and are listed in Table 2. Compliance with the start-up/shutdown CO and NO_x emission limits in Table 2 shall be determined using continuous emissions monitoring systems (CEMS).

Table 2. Hourly Emission Limits During Periods of Start-up or Shutdown

Device	**Hourly Emissions, Each CTG/HRSG, lb/hr**	
	NO_x	**CO**
Combined Cycle Systems	194.0	103.3

Notes:
1. Start-up is defined as the period between initiation of fuel flow until the electrical load of the Combustion Turbine increases to 75% or more of the nameplate capacity.
2. Shutdown is defined as the period beginning when the electrical load of a Combustion Turbine drops below 75% of nameplate capacity and ending when fuel flow has ceased.
3. Combined hours in both start-up and shutdown mode for each Combined Cycle System is limited to 341 hours per year.

Even though VOC emissions are higher during start-up/shutdown operations (and these higher emission estimates are included in the annual VOC emission calculations), it is not practical to establish VOC start-up/shutdown emission limit because of the difficulty in testing for compliance (EPA Reference Methods 25A and 18 manual stack tests are used for VOCs, which are very difficult to conduct during the non-steady-state conditions of startup/shutdown). In addition, a start-up/shutdown modeling analysis is not required for VOCs (there are no air quality standards for VOCs and the relationship between hourly VOC emission rates and ambient ozone concentrations is extremely difficult to determine). Therefore, separate VOC start-up/shutdown emission limits have not been established.

Because emissions of particulate matter (PM)/PM_{10} and SO_2 do not increase during start-up/shutdown, separate start-up/shutdown emission limits are not established for these pollutants.

C. Annual Allowable Emission Limits

Table 3 presents the maximum annual facility PTE considering all permitted sources. Annual operations will be limited by the specific limits on hours of operation for the various operating modes (normal, duct firing, start-up/shutdown). The total allowable emissions in Table 3 include emissions from the proposed emergency generator and fire pump engine, which will only be used for emergency purposes or for testing/maintenance and are limited to a combined 1,000 hours of operation per year. For the sake of demonstrating the calculation of the annual PTE limit, emissions are assumed to be evenly split between the two emergency engines.

Table 3. Average Annual Emissions

Device	Average Annual Emissions, tons per year (TPY)				
	NO_x	CO	VOC	PM_{10}	SO_2
Combined Cycle System 1	95.67	38.3	10.93	62.0	12.0
Combined Cycle System 2	95.67	38.3	10.93	62.0	12.0
Combined Cycle System 3	95.67	38.3	10.93	62.0	12.0
Cooling Towers	N/A	N/A	N/A	15.7	N/A
Diesel Fire Water Pump Engine, 1341 hp	8.05	1.84	0.23	0.23	0.27
Diesel Emergency Generator, 1341 hp	8.05	1.84	0.23	0.23	0.27
TOTAL	303.1	118.6	33.3	202.2	36.5

Note:

1. NO_x emissions will be controlled using low-NOx burners and SCR.
2. CO and VOC emissions will be controlled using an oxidation catalyst.

At full load and 66 degrees Fahrenheit (°F) (the annual average temperature at the site) the heat input of the combustion turbines will be 1,429 MMBtu/hr, and for the duct burners 103 MMBtu/hr (HHV). Normal operation is defined by the applicant at loads above or equal to 75%. The applicant calculated emissions for the combined cycle units during operation at 100% load using 7,039 hours per year, including 4,000 hours per year for duct firing.

Start-up/shutdown for the turbines are defined as loads below 75%. The amount of time a unit has been shutdown will determine whether the subsequent start-up is hot, warm, or cold. According to information from the turbine manufacturer, a hot start-up occurs if a unit has been offline for less than 8 hours, a warm start-up if it has been offline between 8 and 48 hours, and a cold start-up if it has been offline for greater than 48 hours. The applicant calculated start-up/shutdown emissions based on 10 cold starts, 50 warm starts, 100 hot starts, and 160 shutdowns per year. Emissions per start-up and shutdown were provided by the turbine manufacturer. Based on the durations of the various start-ups and shutdown provided, the annual limit on combined hours in both start-up and shutdown mode for each turbine is 341 hours per year.

D. BACT and New Source Performance Standard (NSPS) Emission Limits

Additional emission limits or concentrations required by regulations (e.g., NSPS, BACT) are shown in Table 4 on the following page. No alternate operating scenarios have been proposed by the applicant.

IV. APPLICABLE REGULATIONS

There are two components to the New Source Review (NSR) permitting program codified in Article 4 of the ADEQ regulations: Prevention of Significant Deterioration (PSD) and Nonattainment NSR. The PSD program is applicable in areas that are attaining air quality standards (or are "unclassified"), and it is intended to prevent further deterioration of air quality in the area. Nonattainment NSR applies in areas that are exceeding air quality standards.

In order to trigger the applicability of either of these programs, the source must meet the definition of a major stationary source. As shown in Table 5, the Big Sandy project is a major source because it is a "categorical source" (as in Arizona Administrative Code (A.A.C.) R18-2-401) with potential emissions of a regulated pollutant above the 100 ton per year (tpy) threshold. Because the proposed location of the Big Sandy facility is designated attainment/unclassified for all criteria pollutants, only applicability with the PSD permitting program must be evaluated. The PSD applicability significant emission rate thresholds are exceeded at Big Sandy for NO_x, CO, and PM_{10}.

Table 4. Additional BACT and NSPS Emission Limits

Device	Concentration or Rate Limits				
	NO_x	CO	VOC	PM_{10}	SO_2
Each Combustion Turbine Exhaust Operating in Conditions Other than Start-up	Determined by calculation[1]	--	--	--	SO_2 emissions <150 ppmvd or sulfur fuel content of <0.8% by weight[2]
Each Duct Burner Exhaust	0.2 lb/MMBtu[3]	--	--	--	--
Each Combined Cycle System Exhaust	2.5 ppm, 1-hour rolling average (subject to two-year demonstration period)	2.5 ppm 75-100% load 2.0 ppm, 100% load with duct firing 3-hour rolling average	1.5 ppm 75-100% load 1.6 ppm, 100% load with duct firing 3-hour rolling average	0.012 lb/MMBtu	--

[1] Based on NSPS Subpart GG, 40 Code of Federal Regulations (CFR) 60.332(a)(1).
[2] Based on NSPS Subpart GG, 40 CFR 60.333(a).
[3] Based on NSPS Subpart Db, 40 CFR 60.44b(a)(4)(i).
"--" means that no additional concentration or rate limit is specified for that pollutant.

Notes:

1. Concentration limits are parts per million by volume corrected to 15% oxygen on a dry basis.
2. Parts per million emission limit for NO_x is a 1-hour rolling average calculated from continuous monitors. This emission limit may be reduced to 2.0 ppmvd on a 1-hour rolling average after the first two years of operation based on the NO_x demonstration required by the permit.
3. Emission limits for NO_x and CO are 3-hour rolling averages calculated from continuous monitors. VOC and PM_{10} averaging times are consistent with the stack testing methods (three 1-hour averages).
4. Ammonia emissions associated with the SCR control system will be limited to 7.5 ppmvd on a 24-hour rolling average.
5. To monitor for compliance with 40 CFR Part 60 Subpart GG, NO_x emissions shall be calculated as required by 40 CFR 60.335(c)(1) unless the Combustion Turbines are installed with a controller programmed with an algorithm acceptable to the Administrator and Control Officer that continuously corrects for variations in ambient humidity, temperature, and pressure yielding a relatively constant NO_x concentration when corrected to 15 percent oxygen, in which case the continuous emission monitoring data can be used without the 40 CFR 60.335(c)(1) correction.
6. When multiple or alternative limits apply, the most stringent limit governs.

Table 5. Potential to Emit and Applicability Thresholds

Pollutant	Potential Emissions (TPY)	Major Source Threshold (TPY)	Significance Level for PSD (TPY)	PSD Applicable?
NO_x	303.1	100	40	Yes
CO	118.6	100	100	Yes
VOC	33.3	100	40	No
PM_{10}	202.2	100	15	Yes
SO_2	36.5	100	40	No

The PSD permitting program requirements are contained in A.A.C. R18-2-406 of the ADEQ regulations. The requirements include an analysis of BACT; an ambient air quality impacts analysis for increment consumption and National Ambient Air Quality Standards (NAAQS); a visibility and other air quality related values (AQRV) impact analysis for Class I areas; and an analysis of additional impacts, including growth, soils, vegetation, and visibility impairment.

A. Permitting Requirements

As described in Section IV, the proposed facility is a major source for NO_x, CO, and PM_{10} under the PSD permitting program. The source is also a major source under A.A.C. R18-2-302 of the ADEQ regulations, those implementing the Title V permitting requirements. ADEQ has a unitary permit program so that sources apply for a permit under NSR and Title V concurrently. The permit application submitted by Caithness Big Sandy covers both the PSD and Title V programs.

1. Title V

As a major source for Title V, the proposed Big Sandy project is required to obtain a Class I (Title V) permit. The permit application and its supplements submitted by Caithness Big Sandy list applicable requirements and contains compliance information, as well as a certification of compliance, which are all required as part of a Title V permit application. Title V includes the specification of appropriate monitoring requirements, and as outlined in Section VIII of this document, monitoring provisions are included in the permit.

2. PSD

The facility will have potential emissions above the PSD significance thresholds for

NO_x, CO, and PM_{10}. As a PSD major source, the facility is required by A.A.C. R18-2-406 to obtain a PSD permit. As explained in Section IV, the PSD requirements codified at R18-2-406 are applicable for these pollutants. The requirements include a determination of BACT for NO_x, CO, and PM_{10}, an analysis of the air quality impact of the project, and additional impacts, which are discussed in Sections IV, V, and VI, respectively.

B. Other Applicable Requirements

1. New Source Performance Standards (NSPS)

Federal authority for NSPS requirements (delineated in 40 CFR Part 60) has been delegated to ADEQ, and Article 9 of the ADEQ regulations adopted the NSPS by reference. For the proposed project, the combustion turbines are subject to NSPS Subpart GG, and the duct burners at the heat recovery steam generators are subject to Subpart Db.

NSPS Subpart GG, *Stationary Gas Turbines*, is applicable to turbines with heat input capacities greater than 10 MMBtu/hr. In addition to the requirements of Subpart A, *General Provisions*, the following are the applicable requirements of Subpart GG for the proposed turbines:

- §60.332, Standard for NO_x, includes an equation to calculate allowable NO_x emissions in ppm. From the equation, the nominal NO_x emission rate for the proposed turbines is 75 ppm @15% O_2 (without correction for thermal efficiency), which is much higher than the permitted rate.
- §60.333, Standard for SO_2, specifies SO_2 emissions <150 ppmvd or a sulfur fuel content of <0.8% by weight. Natural gas is the only fuel that will be combusted by the proposed project and it is inherently low in sulfur. Compliance with this standard will be met by burning only pipeline quality natural gas.
- §60.334, Monitoring of Operations, requires monitoring of sulfur and nitrogen content of the fuel being fired in the turbine on a daily basis. A custom schedule for determination of these values may be developed based on the design and operation of the turbines and the characteristics of the fuel supply. The custom schedule shall be substantiated with data and must be approved by the Administrator before it can be used to comply with §60.334(b).
- §60.335, Test Methods and Procedures, specifies the methods to determine the nitrogen and sulfur contents of the fuel, and how to determine compliance with the NO_x and SO_2 standards. Appropriate test

methods are also discussed.

NSPS Subpart Db, *Industrial-Commercial-Institutional Steam Generating Units*, is applicable to duct burners at heat recovery steam generators with heat input capacities greater than 100 MMBtu/hr. In addition to the requirements of Subpart A, *General Provisions*, the following are the applicable requirements of Subpart Db for the proposed duct burners:

- §60.44b(a)(4)(i), Standard for NO_x, specifies that NO_x (expressed as NO_2) not exceed 0.20 lb/MMBtu heat input. From §60.44b(h) this standard applies at all times including start-up, shutdown, and malfunction, and from §60.44b(i) compliance under this section is determined on a 30-day rolling average basis.
- §60.46b(c), Compliance and Performance Test Methods for NO_x, states that compliance shall be determined through performance testing under paragraph (e) or (f), or (g) and (h). §60.46b(f) specifies for duct burners in combined cycle systems, the use of the NO_x and oxygen measurement procedures in 40 CFR Part 60, Appendix A, Method 20.
- §60.49b(a), Reporting and Recordkeeping, requires submittal of notification of the date of initial start-up.
- §60.49b(b), Reporting and Recordkeeping, specifies the submittal of performance test data from the initial performance test.
- §60.49b(d), Reporting and Recordkeeping, requires that records of the amounts of fuel combusted during each day will be maintained.
- §60.49b(g), Reporting and Recordkeeping, specifies the records to be maintained for sources subject to a NO_x standard under §60.44b.
- §60.49b(w), Reporting and Recordkeeping, states that the reporting period for reports is each 6 month period.

Because the BACT requirements for Big Sandy will mandate much lower emissions rates than required by NSPS, a permit streamlining analysis is included in Section IV.C below.

2. Accidental Release

Chemical accidental release prevention requirements have been established in 40 CFR Part 68. Applicability is determined by comparing the amount of a listed substance on-site at a facility to its threshold quantity. Big Sandy has proposed using ammonia in association with the SCR NO_x control system. At the time of application the design specifications for the SCR system was not complete, thus, the type, concentration, and quantity to be stored on-site was not known. If more than a threshold quantity (20,000 pounds for aqueous or 10,000 pounds for anhydrous) will be stored on-site this will trigger the risk management planning requirements. A Risk Management Plan is required by the date on which a regulated substance is first present above the threshold quantity. Consequently, a Risk Management Plan for the storage and use of ammonia will be required before ammonia in excess of the threshold can be stored on-site.

In addition to a Risk Management Plan, under Section 112(r)(1) of the Clean Air Act Big Sandy also has a general duty to identify, prevent, and minimize the consequences of an accidental release of toxic chemicals.

3. Acid Rain

The combined cycle units are considered Stage II affected units under the Title IV Acid Rain Program and an Acid Rain permit must be obtained prior to operation. As part of a supplement to its permit application Big Sandy submitted an Acid Rain permit application. The proposed permit serves as a combined PSD, Title IV, and Title V permit. The permitted emission limits, monitoring, recordkeeping, and reporting requirements of the proposed permit incorporate the applicable Acid Rain provisions of 40 CFR Parts 72, 73, and 75.

As a new plant, Big Sandy does not hold SO_2 allowances and will have to obtain such allowances to sufficiently cover its previous year's emissions as of the allowance transfer deadline. Emission limits for NO_x are not applicable to the project because the Acid Rain provisions only apply to coal-fired units. Monitoring requirements from 40 CFR Part 75 are discussed in Section VI.

C. Regulatory Streamlining

The proposed Big Sandy project is subject to requirements under NSPS that are less stringent than those required in the proposed permit as a result of BACT. The permit has been drafted to reflect the more stringent requirements. The following analysis demonstrates the permit streamlining. Table 6 summarizes the requirements and demonstrates that the streamlined permit conditions are more stringent.

From NSPS Subpart GG, the emission limit for NO_x from the combustion turbines is established in §60.332(a)(1) as 0.01% by volume at 15% O_2, which corresponds to 100 ppmv. NO_x emissions from the turbines will be controlled by dry low-NO_x combustors and further controlled by an SCR system. The BACT analysis results in an emission rate for NO_x of 2.5 ppmvd @ 15% O_2, which is more stringent than the NSPS Subpart GG requirement. This emission limit may be reduced to 2.0 ppmvd after the first two years of operation based on the NO_x demonstration required by the permit. NSPS Subpart Db establishes an emission limit for NO_x of 0.20 lb/MMBtu for the duct burners. The total NO_x emission rate for each combined cycle system equates to 0.012 lb/MMBtu, which is also more stringent than the NSPS requirement.

In addition, the equation used to calculate the NO_x emissions for the steam generating units (§60.46b(f)) was left out of the permit because the applicant has agreed to install CEMS which is more accurate.

Table 6. Permit Streamlining Analysis

Citation	Requirements	Proposed Permit Condition	Comparable Level of Stringency
Emission Limits	Turbine: NO_x: 40 CFR 60.332(a)(1), turbine < 100 ppmvd SO_2: 40 CFR 60.333(a), fuel content <0.8% by weight Duct burners: NO_x: 40 CFR 60.44b(a)(4)(i), $\leq$ 0.20 lb/MMBtu	Combined cycle units: BACT: 2.5 ppmvd @ 15% O_2, 1 hour average* Maximum allowable sulfur content of natural gas 0.75 grains/100 dscf	Permit more stringent
Monitoring	40 CFR Part 75: CEMS for NO_x and O_2 (or CO_2), and CMS for fuel flow 40 CFR 60.334(b), sulfur and nitrogen content of the fuel, daily or custom schedule	CEMS for NO_x and O_2 (or CO_2), and CMS for fuel flow Federal Energy Regulatory Commission-approved agreement for sulfur content	Permit as stringent
Testing	40 CFR 60.8, 60.335(b) and 40 CFR 60.46b(c) and (f), initial source testing and as required by Administrator	Initial performance testing and compliance via CEMS	Permit as stringent
Recordkeeping	40 CFR 60.48b(d), fuel usage, daily 40 CFR 60.48b(g), records	Fuel flow monitor and fuel usage records, records of emission rates and CEMS data	Permit as stringent
Reporting	40 CFR 60.7, 60.334(c), excess emissions 40 CFR 60.48b(a), notifications 40 CFR 60.48b(b), performance test data	Semi-annual reports, excess emissions, performance test data, notifications	Permit as stringent

* This emission limit may be reduced to 2.0 ppmvd on a 1-hour rolling average after the first two years of operation based on the NO_x demonstration required by the permit.

The emission limit for SO_2 in NSPS Subpart GG is either a fuel sulfur content of 0.8% by weight or 150 ppmvd. Pipeline quality natural gas is the only fuel to be combusted in the turbines and it is inherently low in sulfur with a maximum allowable sulfur content in the natural gas of 0.75 grains/100 dscf. This equates to a weight percent of sulfur of 0.0024%, which is much lower than the NSPS limit of 0.8% by weight.

As per Part 75 continuous monitoring is required for NO_x, O_2 (or CO_2), and fuel flow. Test methods specified in the permit are more broad and inclusive of the NSPS-specified method. Recordkeeping and reporting requirements in the permit are as stringent as the NSPS.

V. BEST AVAILABLE CONTROL TECHNOLOGY (BACT)

The PSD regulations under Title I of the Federal Clean Air Act and A.A.C. R18-2-406.A, and the BACT requirements under those regulations, are applicable to the Big Sandy project for NO_x, CO, and PM_{10}. The term "best available control technology" is defined in the ADEQ regulations as follows:

> "an emission limitation, including a visible emissions standard, based on the maximum degree of reduction for each air pollutant listed in R18-2-101(97)(a) which would be emitted from any proposed major source or major modification, taking into account energy, environmental, and economic impact and other costs, determined by the Director in accordance with R18-2-406(A)(4) to be achievable for such source or modification."

A "top-down" approach is recommended for determining BACT, and the analyses are to be performed on a source-by-source and pollutant-by-pollutant basis. This approach essentially ranks potential control technologies for each pollutant in order of effectiveness and ensures that the best technically and economically feasible option is chosen. As described in the Environmental Protection Agency's (EPA) *New Source Review Workshop Manual*, draft (final document never published), October 1990, the general methodology of this approach is as follows:

1. Identify potential control technologies, including combinations of control technologies, for each pollutant subject to PSD review.
2. Evaluate each control technology for technical feasibility; eliminate those determined to be technically infeasible.
3. Rank the remaining technically feasible control technologies in order of control effectiveness.
4. Assume the highest ranking technically feasible control represents BACT, unless it can be shown to result in adverse environmental, energy, or economic impacts.
5. Select BACT.

The NSR Workshop Manual also notes that, to complete the BACT process, an enforceable emission limit representing BACT must be included in the PSD permit. This emission limit must be met on a continual basis at all levels of operation, must demonstrate protection of short term ambient standards, and must be enforceable as a practical matter. In order for the emission limit to be enforceable as a practical matter, the permit must specify a reasonable compliance averaging time, consistent with established reference methods, and must include compliance verification procedures (i.e., monitoring requirements) designed to show compliance or non-compliance on a time period consistent with the applicable emission limit.

As required by PSD regulations, Big Sandy will be using air pollution control techniques for each pollutant subject to review that have been analyzed and are deemed to be "best available control technology," to control emissions from its emitting sources. The applicant provided a BACT analysis in its initial application. This BACT analysis was revised in the application resubmittal in October 2001. The analyses have been reviewed by ADEQ and the results are summarized below for each of the emitting units.

A. Combined Cycle Systems

The CTG/HRSG units will be equipped with an SCR system and low-NO_x combustors to control NO_x emissions to 2.5 parts per million by volume dry (ppmvd) @ 15% oxygen (O_2) (1-hour average; the SCR system will be designed to meet 2.0 ppmvd). This emission limit may be reduced to 2.0 ppmvd on a 1-hour rolling average after the first two years of operation based on the NO_x demonstration required by the permit. An oxidation catalyst will control CO and VOC emissions. Combustion controls will mitigate emissions of PM_{10}. Although not subject to BACT, emissions of SO_x (SO_2 and sulfur trioxide (SO_3)) will be limited by the maximum allowable sulfur content in the natural gas of 0.75 grains/100 dry standard cubic foot (dscf) and 3.1 pounds of SO_2/hr.

1. Particulate Matter Less than 10 Microns (PM_{10})

PM_{10} is a Clean Air Act regulated pollutant defined as particulate matter equal to or less than a nominal aerodynamic particle diameter of 10 microns. Particulate matter is typically described as in-stack or "filterable" and condensible PM. The amount of both filterable and condensible PM_{10} emissions from natural gas-fired combustion turbines should be very small relative to the total exhaust flow. Vendor data on expected PM_{10} emission rates are designed to allow for the high level of test error inherent in sampling for an extremely small quantity of PM_{10} in a very large exhaust flow. In order to reduce the amount of variability/error, longer sampling times than are normally used by stack testers during compliance testing can be used.

There are no known applications of add-on controls for the purpose of controlling PM_{10} from natural gas-fired units, because this fuel has little if no ash that would contribute to the formation of PM or PM_{10}. The applicant has demonstrated that the use of good combustion practices and natural gas represents BACT for PM_{10}.

Table 7. CTG/HRSG BACT Comparison for PM_{10}

RBLC ID	Permit Date	Facility	Process	Control Technology	Emiss. Limit	Emiss. Limit Unit	Basis
		Big Sandy	CTG/HRSG	Good Combustion	0.012	lb/MMBtu	BACT
MI-0267	6/7/01	Renaissance Power LLC	CTG/HRSG	Good Combustion	10.7	lb/hr	BACT
FL-0214	2/5/01	CPV Gulfcoast Power Generating Station	CTG	Combustion Controls	11	lb/hr	BACT
IN-0086	5/9/01	Mirant Sugar Creek LLC	CTG/HRSG	Good Combustion	18	lb/hr	BACT
WV-0014	12/18/01	Panda Culloden Generating Station	CTG	Use of Natural Gas	18	lb/hr	BACT
OK-0036	NG	Stephens Energy Facility	CTG/HRSG	NG	19	lb/hr	BACT
FL-0225	8/14/01 Dft	El Paso Broward Energy Center	CTG/HRSG	Combustion Controls	20	lb/hr	BACT
FL-0226	9/11/01 Dft	El Paso Manatee Energy Center	CTG/HRSG	Combustion Controls	20	lb/hr	BACT
FL-0227	9/11/01 Dft	El Paso Belle Grade Energy Center	CTG/HRSG	Combustion Controls	20	lb/hr	BACT
IN-0085	6/7/01	PSEG Lawrenceburg Energy Facility	CTG/HRSG	Good Combustion	21	lb/hr	BACT
AZ-0034	2/15/01	Harquahala Generating Project	CTG/HRSG	Good Combustion Control	24	lb/hr	BACT
AZ-0033	3/22/01	Mesquite Generating Station	CTG/HRSG	Good Combustion Control	30.4	lb/hr	BACT
MI-0256	1/12/01	Covert Generating Co LLC	CTG/HRSG	Good Combustion	33.8	lb/hr	BACT
AR-0043	2/27/01	Pine Bluff Energy LLC	CTG/HRSG	Good Combustion Practices	0.0065	lb/MMBtu	BACT
AL-0141	4/10/00	GPC-Goat Rock Combined Cycle Plant	CTG/HRSG	Efficient Combustion	0.009	lb/MMBtu	BACT
Al-0162	1/8/01	Autaugaville Combined Cycle Plant	CTG/HRSG	Good Combustion	0.009	lb/MMBtu	BACT
RI-0019	5/3/00	Reliant Energy Hope Gen. Facility	CTG/HRSG		0.009	lb/MMBtu	BACT
AL-0167	1/26/01	Calhoun Power Company I, LLC	CTG	Good Combustion Practices	0.01	lb/MMBtu	BACT
MO-0053	1/1/96	Hawthorne Generating Station	CTG		0.01	lb/MMBtu	BACT
MO-0056	3/30/99	Associated Electric Cooperative	CTG	Good Combustion	0.01	lb/MMBtu	BACT
OK-0041	1/19/00	McClain Energy Facility	CTG/HRSG	Clean Fuels	0.01	lb/MMBtu	BACT
MS-0040	12/31/98	Mississippi Power Plant	CTG		0.011	lb/MMBtu	BACT
AL-0143	3/3/00	AEC-McWilliams Plant	CTG/HRSG	Good Combustion	0.012	lb/MMBtu	BACT
IN-0087	6/6/01	Duke Energy, Vigo LLC	CTG/HRSG	Good Combustion	0.012	lb/MMBtu	BACT
AL-0169	2/5/01	Blount Megawatt Facility	CTG	Good Combustion Practices	0.013	lb/MMBtu	BACT
AR-0035	8/24/00	Panda - Union Generating Station	CTG	Clean Fuels, Proper Operation	0.014	lb/MMBtu	BACT
OK-0043	10/22/01	Webers Falls Energy Facility	CTG	Efficient Combustion	0.015	lb/MMBtu	BACT
MO-0058	5/9/00	Audrain Generating Station	CTG	Good Combustion	0.016	lb/MMBtu	BACT
AL-0132	11/29/99	Tenaska Alabama Generating Station	CTG/HRSG	Efficient Combustion	0.02	lb/MMBtu	BACT
DE-0016	10/17/00	Hay Road Power Complex Units 5-8	CTG	Clean Fuels	0.02	lb/MMBtu	BACT

NG = Not given in RBLC entry

2. *Nitrogen Oxides (NO_x)*

The formation of NO_x from the combustion of fossil fuels can be attributed to two basic mechanisms – fuel NO_x and thermal NO_x. Fuel NO_x results from the oxidation of organically bound nitrogen in the fuel during the combustion process, and generally increases with increasing nitrogen content of the fuel. Because natural gas contains only small amounts of nitrogen, little fuel NO_x is formed during combustion.

The vast majority of the NO_x produced during the combustion of natural gas is from thermal NO_x, which results from a high-temperature reaction between nitrogen and oxygen in the combustion air. The generation of thermal NO_x is a function of combustion chamber design and the turbine operating parameters, including flame temperature, residence time (i.e., the amount of time the hot gas mixture is exposed to a given flame temperature), combustion pressure, and fuel/air ratios at the primary combustion zone. The rate of thermal NO_x formation is an exponential function of the flame temperature.

The reduction of NO_x emissions can be achieved by combustion controls and post-combustion flue gas treatment (i.e., NO_x is removed from the exhaust stream after it is generated). The applicant considered a number of measures for the control of NO_x emissions from the proposed project, including both in-combustor controls considered included water (or steam) injection and the use of dry low-NO_x combustors. SCR, Selective Non-Catalytic Reduction (SNCR), $SCONO_x$, and XONON were considered as post-combustion NO_x control systems. A comparison of the control systems proposed by the applicant and previously permitted control systems taken from the RACT/BACT/LAER Clearinghouse (RBLC) is presented in Table 8.

For large gas turbines such as those proposed, water and steam injection have been largely superseded by dry low-NO_x (DLN) combustors, due to the superior emission control performance and increased efficiency. DLN combustors are also effective in achieving lower NO_x emission levels without the need for large volumes of purified water. Both dry low-NO_x burners and water injection result in higher VOC and CO emissions than uncontrolled turbines, but these effects will be minimized by high combustion temperatures, adequate excess air, and good air-to-fuel mixing during combustion.

Among post-combustion control systems, the XONON catalytic system was rejected because it is not technically feasible. XONON is an emerging technology and is not commercially available at this time for CTGs of the size proposed for this project. SNCR was also rejected as a possible control system because the technology requires gas temperatures in the range of 1200° to 2000°F, and the exhaust temperature for the proposed turbines, i.e. 600°F, is below the minimum SNCR operating temperature.

Table 8. CTG/HRSG BACT Comparison for NO_x

RBLC ID	Permit Date	Facility	Process	Control Technology	Emiss. Limit	Emiss. Limit Unit	Basis
		Big Sandy	CTG/HRSG	SCR, Dry Low NOx Burner	2.5/2.0	ppmv	BACT
CA	10/27/00	Otay Mesa	CTG/HRSG	SCONOx or SCR	2	ppmv	BACT
CT-0148	6/22/99	Lake Road Generating Company	CTG	SCR, Dry Low NOx Burner	2	ppmv	LAER
MA-0024	**4/16/99**	**ANP Blackstone**	**CTG**	**SCR, Dry Low NOx Burner**	**2**	**ppmv**	**LAER**
MA-0025	**8/4/99**	**ANP Bellingham**	**CTG**	**SCR, Dry Low NOx Burner**	**2**	**ppmv**	**LAER**
MA-0029	**9/29/99**	**Sithe Mystic Development**	**CTG/HRSG**	**SCR, Dry Low NOx Burner**	**2**	**ppmv**	**BACT**
RI-0019	**5/3/00**	**Reliant Energy Hope Gen. Facility**	**CTG/HRSG**	**SCR, Dry Low NOx Burner**	**2**	**ppmv**	**BACT**
AZ	**4/30/02**	**Gila Bend Power Generation Station**	**CTG/HRSG**	**SCR, Dry Low NOx Burner**	**2.5/2.0**	**ppmv**	**BACT**
AZ-0033	3/22/01	Mesquite Generating Station	CTG/HRSG	SCR, Dry Low NOx Burner	2.5	ppmv	BACT
AZ-0034	2/15/01	Harquahala Generating Project	CTG/HRSG	SCR, Dry Low NOx Burner	2.5	ppmv	BACT
CA	12/2/99	Sutter Power Plant	CTG/HRSG	SCR, Dry Low NOx Burner	2.5	ppmv	BACT
CA	5/30/01	Contra Costa	CTG/HRSG	SCR, Dry Low NOx Burner	2.5	ppmv	BACT
CA	12/18/01	Elk Hills Power Project	CTG/HRSG	SCR, Dry Low NOx Burner	2.5	ppmv	BACT
FL-0225	8/14/01 Dft	El Paso Broward Energy Center	CTG/HRSG	SCR, Dry Low NOx Burner	2.5	ppmv	BACT
FL-0226	9/11/01 Dft	El Paso Manatee Energy Center	CTG/HRSG	SCR, Dry Low NOx Burner	2.5	ppmv	BACT
FL-0227	9/11/01 Dft	El Paso Belle Grade Energy Center	CTG/HRSG	SCR, Dry Low NOx Burner	2.5	ppmv	BACT
NH-0011	4/26/99	AES Londonderry, LLC	CTG	SCR, Dry Low NOx Burner	2.5	ppmv	BACT
NH-0012	NG	Newington Energy LLC	CTG	SCR, Dry Low NOx Burner	2.5	ppmv	LAER
PA-0160	10/10/00	Calpine Construction Finance Co.	CTG	SCR, Dry Low NOx Burner	2.5	ppmv	LAER
WA-0288	9/4/01	Longview Energy Development	CTG/HRSG	SCR	2.5	ppmv	BACT
DE-0016	10/17/00	Hay Road Power Complex Units 5-8	CTG	SCR, Dry Low NOx Burner	3	ppmv	LAER
IN-0085	6/7/01	PSEG Lawrenceburg Energy Facility	CTG/HRSG	SCR	3	ppmv	BACT
IN-0086	5/9/01	Mirant Sugar Creek LLC	CTG/HRSG	SCR	3	ppmv	BACT
AR-0035	8/24/00	Panda - Union Generating Station	CTG	SCR, Dry Low NOx Burner	3.5	ppmv	BACT
AR-0040	12/29/00	Duke Energy Hot Springs	CTG/HRSG	SCR, Dry Low NOx Burner	3.5	ppmv	BACT
FL-0214	2/5/01	CPV Gulfcoast Power Generating STN	CTG	SCR, Dry Low NOx Burner	3.5	ppmv	BACT
MI-0267	6/7/01	Renaissance Power LLC	CTG/HRSG	SCR, Dry Low NOx Burner	3.5	ppmv	BACT
OK-0036	NG	Stephens Energy Facility	CTG/HRSG	SCR, Dry Low NOx Burner	3.5	ppmv	BACT
OK-0043	10/22/01	Webers Falls Energy Facility	CTG	SCR, Dry Low NOx Burner	3.5	ppmv	BACT
WI-0174	9/20/00	Badger Generating Co LLC	CTG/HRSG	SCR, Dry Low NOx Burner	3.5	ppmv	BACT
WV-0014	12/18/01	Panda Culloden Generating Station	CTG	SCR, Dry Low NOx Burner	3.5	ppmv	BACT

NG = Not given in RBLC entry

The SCR process is a post-combustion control technology in which injected ammonia (NH_3) reacts with NO_x in the presence of a catalyst to form water and nitrogen. The catalyst's active surface is usually a noble metal, base metal (titanium or vanadium) oxide, or a zeolite-based material. The geometric configuration of the catalyst body is designed for maximum surface area and minimum back-pressure on the turbine. An ammonia injection grid is located upstream of the catalyst body and is designed to disperse ammonia uniformly throughout the exhaust flow before it enters the catalyst unit. The desired level of NO_x emission reduction is a function of the catalyst volume and ammonia-to-NO_x (NH_3/NO_x) ratio. For a given catalyst volume, higher NH_3/NO_x ratios can be used to achieve higher NO_x emission reductions, but can result in undesired increased levels of unreacted NH_3 (called ammonia slip).

SCR has been demonstrated to be effective at numerous installations throughout the United States. Typically SCR is used in conjunction with other wet or dry NO_x combustion controls (e.g., DLN). Because SCR is a post-combustion control, emissions from both turbines and duct burners can be controlled.

$SCONO_x$ is another type of post-combustion control. The $SCONO_x$ system uses a proprietary potassium carbonate coated oxidation catalyst to remove both NO_x and CO. The $SCONO_x$ system does not use a reagent such as ammonia but instead utilizes natural gas as the basis for a proprietary catalyst regeneration process. The nitrogen oxide (NO) present in the flue gas is reduced in a two-step process. First, NO is oxidized to NO_2 and adsorbed onto the catalyst. For the second step, a regenerative gas is passed across the catalyst periodically. This gas desorbs the NO_2 from the catalyst in a reducing atmosphere of hydrogen (H_2) which results in the formation of nitrogen (N_2) and water (H_2O) as the desorption products. For the regeneration/desorption step to occur there must be no oxygen (O_2) present during this step. The CO present in the flue gas is oxidized to carbon dioxide (CO_2) as part of the $SCONO_x$ process.

From the analysis, the highest ranking technically feasible control for NO_x is considered to be the use of either SCR or $SCONO_x$ in conjunction with dry low-NO_x combustors. An analysis of the cost-effectiveness for $SCONO_x$ at 1.0 and 2.5 ppmvd at 15% O_2, and SCR at 2.0 and 2.5 ppmvd at 15% O_2 was used to determine the highest ranking, economically feasible control. Note that $SCONO_x$ also controls CO and does not require ammonia, and these factors were taken into account in the cost-effectiveness analysis.

The cost-effectiveness of $SCONO_x$ when compared to SCR results in $SCONO_x$ being considered not economically feasible at either 2.5 or 1.0 ppmvd at 15% O_2. The total dollar per ton and incremental cost-effectiveness of SCR at NO_x levels of 2.5 and 2.0 ppmvd at 15% O_2 were also investigated. The cost-effectiveness for 2.0 ppmvd is $1,667/ton and the incremental cost-effectiveness is $11,830/ton.

After considering the available data, and the emission limits for other recently permitted similar projects, ADEQ concludes that DLN combustors in combination with an SCR control system that reduces NO_x, with or without duct firing, to 2.0 ppmvd at 15% O_2 represents BACT for the CTG/HRSG. Considering both the total dollar per ton cost and the incremental cost of controlling at a level of 2.0 ppmvd (incremental cost is within an acceptable range at $11,830[1]) and to ensure a level playing field with other facilities, ADEQ determines that SCR at a level of 2.0 ppmvd is economically feasible.

The emission limit is initially proposed at 2.5 ppmvd (1-hr average) with a demonstration period that may reduce the emission limit after the first two years of operation based on the NO_x demonstration required by the permit. ADEQ is allowing the two-year demonstration period given that a 2.0 ppmvd NO_x BACT limit has only recently been demonstrated. The permit states that the emission limit will be reduced to 2.0 ppmvd at 15% O_2, excluding periods of start-up and shutdown, after the first two years of operation. If the facility has not been able to reasonably and consistently meet a NO_x limit of 2.0 ppmvd, the facility is required to submit a written request to the Director prior to the two year anniversary, requesting a different limit not to exceed 2.5 ppmvd. The Department will review the request and determine the final emission limit for the remaining permit term.

As noted above, operation of SCR systems can result in undesired emissions of unreacted NH_3, or ammonia slip. In a supplemental data submittal after the October 2001 revised application, the applicant proposed an ammonia slip level of 7.5 ppmvd. After evaluating ammonia slip limits for other recently permitted similar projects, ADEQ established an ammonia slip emission limit of 7.5 ppmvd at 15% O_2 (24-hour average).

3. *Carbon Monoxide (CO)*

CO is a product of incomplete combustion. CO formation is limited by ensuring complete and efficient combustion of the fuel in the combustion turbine. High combustion temperatures, adequate excess air, and good air/fuel mixing during combustion minimize CO emissions. Measures taken to minimize the formation of NO_x during combustion may inhibit complete combustion, which could increase CO emissions. Lowering combustion temperatures through premixed fuel combustion can be counterproductive with regard to CO emissions. However,

[1] The value calculated by the Department is slightly higher than that calculated by the source ($11,126) due to an error in the capital recover factor the source used.

improved air/fuel mixing inherent in newer combustor designs and control systems limits the impact of fuel staging on CO emissions.

The applicant considered catalytic oxidation and good combustion controls as possible control technologies. As noted previously, $SCONO_x$ can control both NO_x and CO, and the additional control of CO was incorporated into the cost analysis. $SCONO_x$ was rejected for economic considerations and is not considered further. An oxidation catalyst represents the most stringent control option, thus, no further analysis of control technologies is required.

A comparison of the control systems considered by the applicant are presented and compared with previously permitted CO control systems taken from the RBLC in Table 9. A review of the RBLC data in Table 9 indicates that combined cycle projects have recently been permitted both with and without an oxidation catalyst.

The applicant is proposing the use of an oxidation catalyst, in addition to combustion controls, to reduce CO to 2.5 ppmvd at 15% O_2 for 75-100% load and 2.0 ppmvd at 15% O_2 for 100% load with duct firing, both on a 3-hour average. Upon review of the data, ADEQ concurs with and approves the applicant's BACT proposal.

B. Cooling Towers

1. Particulate Matter Less than 10 Microns (PM_{10})

Particulates are emitted from cooling towers when small droplets of cooling water, called drift, are emitted and evaporate. The dissolved and suspended materials in the drift can become airborne particles when the water around them evaporates. The size distribution of the emitted particulates includes particles in both the PM and PM_{10} range.

There are two primary factors that control the amount of PM_{10} from the cooling tower: the total dissolved solids (TDS) in the cooling tower water and the droplet drift rate. A droplet drift rate of 0.0005 percent (achieved through the use of high efficiency drift eliminators on the cooling tower) was determined to represent BACT for cooling towers. The BACT limit is based on vendor guarantees and is consistent with the most stringent limits listed in the RBLC.

The TDS is the second parameter affecting PM_{10} from the cooling towers. The TDS proposed by the applicant, 5,932 parts per million (ppm), is based on eight recirculations. This limit is a balance between the need to keep the TDS low and the need to minimize water usage (which forces the TDS higher). The 5,932 ppm TDS limit is established as a permit condition, as well as the compliance demonstration requirements to perform monthly TDS laboratory analyses and daily measurements of conductivity (this is a surrogate parameter directly related to TDS concentrations).

Table 9. CTG/HRSG BACT Comparison for CO

RBLC ID	Permit Date	Facility	Process	Control Technology	Emiss. Limit	Emiss. Limit Unit	Basis
		Big Sandy	CTG/HRSG	Oxidation Catalyst	2.0,2.5	ppmv	BACT
WA-0288	9/4/01	Longview Energy Development	CTG/HRSG	Oxidation Catalyst	2	ppmv	BACT
WI-0114	1/13/95	LS Power	CTG	Good Combustion	2	ppmv	BACT
CT-0148	6/22/99	Lake Road Generating Company	CTG	Oxidation Catalyst	3	ppmv	BACT
MI-0267	6/7/01	Renaissance Power LLC	CTG/HRSG	Oxidation Catalyst	3	ppmv	BACT
AZ-0033	3/22/01	Mesquite Generating Station	CTG/HRSG	Oxidation Catalyst	4	ppmv	BACT
CA	12/2/99	Sutter Power Plant	CTG/HRSG	Oxidation Catalyst	4	ppmv	BACT
CA	12/18/01	Elk Hills Power Project	CTG/HRSG	Oxidation Catalyst	4	ppmv	BACT
WI-0174	9/20/00	Badger Generating Co LLC	CTG/HRSG	Oxidation Catalyst	4	ppmv	BACT
MI-0256	1/12/01	Covert Generating Co LLC	CTG/HRSG	Oxidation Catalyst	5	ppmv	BACT
CA	5/30/01	Contra Costa	CTG/HRSG	Oxidation Catalyst	6	ppmv	BACT
CA	10/27/00	Otay Mesa	CTG/HRSG	Oxidation Catalyst	6	ppmv	BACT
IN-0085	6/7/01	PSEG Lawrenceburg Energy Facility	CTG/HRSG	Good Combustion	6	ppmv	BACT
FL-0225	8/14/01 Dft	El Paso Broward Energy Center	CTG/HRSG	Combustion Controls	7.4	ppmv	BACT
FL-0226	9/11/01 Dft	El Paso Manatee Energy Center	CTG/HRSG	Combustion Controls	7.4	ppmv	BACT
FL-0227	9/11/01 Dft	El Paso Belle Grade Energy Center	CTG/HRSG	Combustion Controls	7.4	ppmv	BACT
WV-0014	12/18/01	Panda Culloden Generating Station	CTG	Good Combustion	8.2	ppmv	BACT
DE-0016	10/17/00	Hay Road Power Complex Units 5-8	CTG	Good Combustion	9	ppmv	BACT
FL-0214	2/5/01	CPV Gulfcoast Power Generating STN	CTG	Combustion Controls	9	ppmv	BACT
FL-0223	11/4/99	Lake Worth Generating, LLC	CTG	Combustion Design	9	ppmv	BACT
IN-0086	5/9/01	Mirant Sugar Creek LLC	CTG/HRSG	Good Combustion	9	ppmv	BACT
IN-0087	6/6/01	Duke Energy, Vigo LLC	CTG/HRSG	Good Combustion	9	ppmv	BACT
FL-0202	8/17/92	Orlando Cogen	CTG	Combustion Control	10	ppmv	BACT
MO-0049	8/19/99	Kansas City Power & Light	CTG/HRSG	Oxidation Catalyst	10	ppmv	BACT
MO-0056	3/30/99	Associated Electric Cooperative, Inc.	CTG	Good Combustion	10	ppmv	BACT
OK-0036	NG	Stephens Energy Facility	CTG/HRSG	NG	10	ppmv	BACT
OK-0043	10/22/01	Webers Falls Energy Facility	CTG	Combustion Control	10	ppmv	BACT
PA-0160	10/10/00	Calpine Construction Finance Co.	CTG	None	10	ppmv	BACT
AZ-0034	2/15/01	Harquahala Generating Project	CTG/HRSG	Oxidation Catalyst	37	lb/hr	BACT

NG = Not given in RBLC entry

ADEQ also requested the applicant consider a dry, air-cooled condenser in lieu of a wet cooling tower as the top control option in its cooling tower BACT analysis. The applicant provided cost data for such a dry system that demonstrated that the technology was not economically feasible when compared to a wet cooling tower. Consequently, the Department concludes that the high efficiency drift eliminators with an efficiency of 0.0005 percent are BACT for PM_{10} for the cooling towers.

Recently, the Mohave County Board of Supervisors passed a resolution to require all new power plants in Mohave County to install dry cooling technology if the facility has the potential to deplete available water in the County's aquifers. This decision cannot be used to determine what is BACT for the facility, but would instead be addressed with the company directly by the Board of Supervisors. According to the applicant, they are currently addressing this issue with Mohave County to determine its applicability to the project. The Department is issuing this permit on the basis that it meets all current State and Federal regulatory requirements. Any applicable construction requirements specific to Mohave County will be addressed in other actions outside the jurisdiction of the Air Quality Division of ADEQ.

C. Fire Water Pump and Emergency Generator

The proposed facility includes two diesel engines (fire water pump and emergency generator), which will be operated only for testing/maintenance or emergencies. The limitation on the hours of operation (i.e., combined 1,000 hours per year) results in minimal emissions. As a result, BACT for the engines was determined to be good combustion control as provided by modern engine control systems.

VI. MONITORING REQUIREMENTS

A. Compliance Assurance Monitoring (CAM)

Pursuant to 40 CFR 64.2(b)(iii), the subject facility is not subject to CAM for NO_x because it is subject to Acid Rain Program requirements, and is not subject to CAM for CO because the facility will install a CEMS to measure CO emissions.

B. Combined Cycle Systems With and Without Duct Firing

The Combined Cycle Systems may be operated in combined cycle operation and may only burn pipeline quality natural gas.

PM: The units are subject to a PM_{10} emission limitation resulting from the use of BACT.

Verification through annual performance testing will fulfill the requirements for periodic monitoring. Emissions will be determined using the performance test results and monitored fuel usage data.

Opacity: The Combined Cycle Systems are subject to the opacity standard of 10% as is consistent with previous permitting projects in the State (i.e., Griffith Energy). Natural gas is a clean burning fuel and operation of these types of units generally indicate that opacity problems are rare.

NO_x: The units are subject to a NO_x emissions limitation resulting from the use of BACT. The source is required to operate, certify, maintain, and calibrate compliance CEMS for NO_x. The CEMS will comply with the applicable requirements of 40 CFR Part 75. A Relative Accuracy Test Audit (RATA) is required annually for the monitors. The source is also required to develop an Operations and Maintenance plan for the SCR system.

CO: The units are subject to a CO emissions limitation resulting from the use of BACT. The source is required to operate, certify, maintain, and calibrate compliance CEMS for CO. The CEMS will comply with the applicable provisions of 40 CFR Part 60 and 40 CFR Part 75. A RATA is required annually for the monitors.

SO_2: The units are subject to a limit of 0.75 grains of sulfur/100 dscf in the natural gas and a limit of 3.1 pounds of SO_2 per hour. This limit will be demonstrated by the permittee maintaining a vendor-provided copy of that part of the Federal Energy Regulatory Commission (FERC)-approved tariff agreement that contains the sulfur content and the lower heating value of the pipeline quality natural gas. Emissions will be determined using the sulfur content in the fuel and monitored fuel usage data.

VOC: The units are subject to a VOC emissions limitation due to the additional benefits resulting from the use of BACT to control CO emissions. Verification through annual performance testing will fulfill the requirements for periodic monitoring. Emissions will be determined using the performance test results and monitored fuel usage data.

Ammonia: The units are subject to an ammonia slip emission limit. The source is required to operate, certify, maintain, and calibrate ammonia flow meters on each SCR unit to monitor the ammonia injection rate.

Flow and Diluent: As per 40 CFR Part 75, fuel flow meters are required on each fuel line to monitor the unit-specific fuel flow to the combustion turbines and duct burners. O_2 (or CO_2) diluent gas monitors are required on each combined cycle system. The monitors will comply with the applicable provisions of 40 CFR Part 60 (Appendices B and F) and 40

CFR Part 75.

VII. TESTING REQUIREMENTS

A. Combined Cycle Systems with Duct Firing

Big Sandy is required to perform initial performance tests for NO_x in accordance with 40 CFR 60.46b(c) and (f). Annual stack testing for NO_x and CO is not specified separately because annual testing will be conducted as part of the Relative Accuracy Test Audits (RATA) for the CEMS. Performance testing for ammonia at full load with duct firing will be conducted initially and every two years thereafter. Catalyst life expectancy for SCR is typically given as three years, performing a stack test every two years will determine if there is early catalyst degradation. An initial performance test and annual tests thereafter for PM_{10} and VOC will be used to demonstrate compliance with the PM_{10} and VOC emission limits. An initial performance test for SO_2 will be used to demonstrate compliance with the 3.1 pounds of SO_2 per hour emission limitation. Testing will be performed at full load and at reduced load conditions.

B. Combined Cycle Systems without Duct Firing

Big Sandy is required to perform initial performance tests for SO_2 and the nitrogen and sulfur content of the fuel in accordance with 40 CFR 60.335. An initial performance test upon start-up is required for CO, PM_{10}, and VOC. Thereafter, annual tests for CO, PM_{10}, and VOC will be used to demonstrate compliance with the emission limits, unless all emission limits are met with supplemental firing.

VIII. IMPACTS TO AMBIENT AIR QUALITY

A. Ambient Air Quality Impacts Analysis

1. General

As noted in Section IV, the PSD ambient air quality analysis requirements are applicable to the Big Sandy project for the pollutants NO_x, CO, and PM_{10}. EPA's guidance for performing PSD air quality analyses is set forth in Chapter C of the October 1990 New Source Review Workshop Manual, as well as in 40 CFR Part 51 Appendix W. The modeling analysis is performed in two steps: a "facility-only" significant impact analysis, and if required a cumulative impact or "multi-source" analysis. The preliminary analysis estimates ambient concentrations resulting from the proposed project for pollutants that trigger PSD requirements.

The results of the significant impact modeling determine whether the Applicant must perform a full impact analysis. If the ambient impacts are greater than the Significant Impact Levels (SILs), then the extent of the Significant Impact Area (SIA) of the proposed project is determined.

The full impact analysis expands the "facility-only" significant impact analysis by considering emissions from both the proposed project as well as other sources in the SIA (and other sources outside of the SIA that nonetheless cause significant impacts in the proposed source's SIA). The results from the full impact analysis are used to demonstrate compliance with NAAQS and PSD increments. The source inventory for the cumulative NAAQS analysis includes all nearby sources that have significant impacts within the proposed source SIL, while the source inventory for the cumulative PSD analysis is limited to increment-effecting sources (new sources and changes to existing sources that have occurred since the applicable increment baseline date).

The full impact analysis is limited to receptor locations within the proposed project's SIA. The modeling results from the NAAQS cumulative impact analysis are added to representative ambient background concentrations and the total concentrations are compared to the NAAQS. Conversely, the modeled air quality impacts for all increment-consuming sources are directly compared to the PSD increments to determine compliance (without consideration of ambient background concentrations).

According to EPA guidance, if the cumulative impact analysis demonstrates violations of any NAAQS or PSD increment, the proposed facility can still be permitted if it can be demonstrated that the facility does not result in ambient impacts that exceed the SIL at the same time and location of any modeled violation. In other words, the facility must demonstrate that it would not "significantly contribute" to any modeled violation.

2. *Modeling Methodology*

a. Source Data for the Project

The PSD ambient air quality analysis requirements are applicable for the pollutants NO_x, CO, and PM_{10}. In addition, ADEQ requested an analysis for the pollutant SO2.

A detailed load-screening analyses was first conducted to determine which operating scenarios resulted in maximum ambient impacts for each pollutant. These scenarios included 100% load operations (with and without HRSG firing and evaporative cooling), 75% load operations, and a startup/shutdown scenario. Previous modeling analyses submitted by the applicant’s consultant utilized conservative assumptions of 100% load emissions with 75% load flow rates for short term modeling results. ADEQ reevaluated these load screening results using more accurate conditions of matching the corresponding short term emission rates with the 75% and 100% flow rates. Table 10 presents the emissions data for the worst-case scenarios, along with exit velocities for both 100% and 75% loads. More detailed information on these sources can be found in the applicant's Air Quality Modeling Report (Greystone, Oct 2001).

b. NAAQS and PSD Increment Inventory

Various other sources within 100 kilometers were modeled as part of the NAAQS inventory. The emissions, stack parameters, and locations for these sources are presented in Table 11.

c. Computer Model Used

The typical refined model used in air quality analyses is the Industrial Source Complex Short Term Model (ISCST3, version 00101). However, because of the importance of building downwash for this project, the ISCPRIME (version 98069) model was used by the applicant. The ISCPRIME model has been specifically developed to more accurately predict the impacts from downwash. The model was approved for use by ADEQ after consultation and approval from EPA Region 9.

For modeling Class I impacts greater than 50 kilometers away, the applicant used the CALPUFF model, as discussed in the modeling protocol and the revised Air Quality Modeling Report, (Greystone, October 2001).

d. Receptor Grid

For purposes of demonstrating compliance with the PSD increment, the NAAQS and the Arizona Ambient Air Quality Guidelines (AAAQGs), a receptor grid was created with sufficient density to determine the maximum model-predicted impact within the surrounding ambient air (inclusive of process area where applicable). Receptor elevations were derived from the United States Geological Service (USGS) Digital Elevation Model (DEM) data. The finest grid spacing was set at 30 meters for the project boundary and the hilly area to the north of the defined process area. In addition, 7 discrete locations were also modeled, as requested by ADEQ.

Table 10. Source Emissions and Stack Parameters for Big Sandy Sources

Source ID	UTM Easting (m)	UTM Northing (m)	Elevation (m)	NO_x (tpy)	CO (g/s)	SO_2 (g/s)	PM_{10} (g/s)	Stack Ht (m)	Temp (K)	Velocity (m/s)	Diameter (m)
North CT/HRSG Stack	267599	3838580	645	95.7	13.1 [a]	0.4	1.892	50.29	366 /364	15.2/12.8	5.03
Middle CT/HRSG Stack	267593	3838521	645	95.7	13.1 [a]	0.4	1.892	45.72	366 /364	15.2/12.8	5.03
South CT/HRSG Stack	267592	3838491	645	95.7	13.1 [a]	0.4	1.892	45.72	366 /364	15.2/12.8	5.03
North Cooling Tower Cell 1	267610	3838613	645	NA	NA	NA	0.039	12.65	308	8.45	5.03
Cell 2	267625	3838613	645	NA	NA	NA	0.039	12.65	308	8.45	10.07
Cell 3	267640	3838612	645	NA	NA	NA	0.039	12.65	308	8.45	10.07
Cell 4	267654	3838612	645	NA	NA	NA	0.039	12.65	308	8.45	10.07
South Cooling Tower Cell 1	267624	3838408	645	NA	NA	NA	0.052	12.65	308	8.45	10.07
Cell 2	267609	3838408	645	NA	NA	NA	0.052	12.65	308	8.45	10.07
Cell 3	267594	3838408	645	NA	NA	NA	0.052	12.65	308	8.45	10.07
Cell 4	267580	3838409	645	NA	NA	NA	0.052	12.65	308	8.45	10.07
Cell 5	267565	3838409	645	NA	NA	NA	0.052	12.65	308	8.45	10.07
Cell 6	267550	3838410	645	NA	NA	NA	0.052	12.65	308	8.45	10.07
Cell 7	267536	3838410	645	NA	NA	NA	0.052	12.65	308	8.45	10.07
Cell 8	267521	3838410	645	NA	NA	NA	0.052	12.65	308	8.45	10.07

* CO emissions were modeled with worst case start-up emissions of 103 lbs/hr to assure compliance. CO emissions for normal operating conditions are estimated to be no more than 8 lbs/hr per stack.

Table 11. Major Source Emissions and Stack Parameters

Source Description	UTME (m)	UTMN (m)	Distance to SGS (km)	Elevation (m)	Emissions (g/s)			Height (m)	Temp (k)	Velocity (m/s)	Diameter (m)
					PM_{10}	***SO_2***	***NO_x***				
North Star Steel	218192	3892700	73.3	893	3.26	2.32	16.64	27.74	789	5.57	0.91
Chemstar Lime	290200	3932700	96.8	1570	8.07	18.39	22.49	51.2	513	14.90	2.44
Phelps Dodge-Bagdad	297000	3829200	30.9	1158	18.02	0.58	11.76	18.9	294	13.0	0.24
El Paso Natural Gas/ Dutch Flats	225000	3830000	43.5	634	NA	NA	3.16	12.19	752	39.6	1.22
El Paso Natural Gas/ Hackberry	253900	3800000	58.3	1148	NA	NA	11.45	10.67	595	6.5	3.99
Ford Motor CO	213700	3863300	59.3	579	NA	NA	0.3	7.92	411	3.35	0.25
Griffith Energy LLC	213800	3882500	69.4	758	5.01	1.44	7.80	39.62	350	11.88	5.79
Mojave Pipeline –Topock	180958	3845700	86.9	384	NA	NA	3.28	21.33	561	26.20	0.97
Enviroverde-Barber	266347	3837091	1.95	593	0.89	NA	NA	8.69	418	19.81	0.97
El Paso Natural Gas Compliance Serv. Dept	340447	3906269	99.4	1597	NA	3.22	NA	10.67	595	6.5	3.99

e. Meteorological Data

Onsite meteorological data was collected for the period March 25, 2000, through March 24, 2001. This data set had a valid recovery rate of approximately 100%, and was approved as an representative onsite data set for regulatory modeling purposes.

f. Downwash and Good Engineering Practice (GEP)

Because of the effect of building downwash, the building wake option was used in ISCPRIME. A revised version of EPA's BPIP program, BPIP-PRIME, was used to calculate the building downwash parameters for input to ISCPRIME. All the facility stacks are subject to downwash. The building locations and GEP analysis were independently confirmed. All stacks are below the minimum 65 meter allowable GEP height, therefore all stack heights are fully creditable.

g. Background Concentrations

The Department approved the use of PM_{10} air quality data collected near the project property from March 25, 2000, through March 24, 2001. The background NO_x concentrations were taken from the North Star Steel facility near Kingman, Arizona in 1992-1993. These concentrations are listed in Table 12.

Table 12. Ambient Background Monitored Air Quality Data

Pollutant	Averaging Period	Background Concentration	NAAQS
PM_{10}	24-hour	56.9	150
	Annual	19.8	50
NO_x	Annual	20	100

3. *Modeling Results*

a. Significant Impact Modeling and SIA

The applicant demonstrated that only PM_{10} and NO_x emissions had predicted maximum concentrations greater than the significant impact level (SIL) for any of the relevant averaging periods. Table 13 presents results from the significant impact analysis. The maximum distance of the significant impact area for PM_{10} (for the 24-hour averaging period) is just over 6 kilometers from the location of unit 1 for the facility. The maximum distance of the significant impact area for NO_x is 5100 meters to the north. Therefore, a full impact analysis was conducted for these pollutants.

Because modeled ambient concentrations were lower than the SILs for CO and SO_2, no additional modeling was required for these pollutants. The modeling results for the pollutant SO_2 demonstrated that maximum impacts were slightly less than the 24-significance level (SIL) of 5 micrograms per cubic meter ($\mu g/m^3$). Previous modeling submittals by the applicant indicated that maximum modeled SO_2 concentrations to be slightly higher then the SIL, but used the overly conservative assumption of 100% load SO_2 emissions with 75% load flow rates. When SO_2 was remodeled with "matched emissions and flows", the maximum SO_2 concentrations are less the SIL for any of the relevant averaging periods.

b. Comparison of Big Sandy Impacts with NAAQS and PSD Increments

The full impact analysis expanded the significant impact analysis by considering emissions from both the proposed project as well as other sources in the SIA. Maximum modeled concentrations for the cumulative analyses are presented in Tables 13 and 14. Concentrations are compared to both the NAAQS and the Class II and Class I PSD increments. All ambient impacts are less than the NAAQS and the PSD increments.

The maximum impact for the 24-hour PM_{10} Class II increment is 20.8 $\mu g/m^3$, located just north of the process area boundary, approximately 235 meters from stack 1. The maximum impact is approximately 69% of the PSD Class II 24-hour increment of 30 $\mu g/m^3$.

The emergency generator and fire pump engine were not explicitly modeled in the analyses. Treatment of the emergency equipment in the modeling analysis was discussed at length between ADEQ and the applicant's consultant. ADEQ approved a simplified method for evaluating the impacts that considered the 24-hour PM_{10} Class II increment. The overall facility modeled PM_{10} concentrations would be linearly increased by the ratio of the PM_{10} hourly emission rate for the emergency equipment versus the facility total PM_{10} hourly emission rate. The emergency equipment "impact factor" is calculated at 10.1%. Given the most recent modeling result of 20.8 μg/m^3 for the PM_{10} 24-hr impact, the estimated overall impact is 22.9 μg/m^3, which is less than the PSD increment.

Table 13. Maximum Air Quality Impacts from Big Sandy Sources

Pollutant	Averaging Period	Maximum Project Impact ($\mu g/m^3$)	Location UTME (m)	Location UTMN (m)	Distance from Big Sandy (meters)	Significant Impact Level ($\mu g/m^3$)	Maximum Distance of SIA (meters)
NO_2	Annual	2.44	268342	3840841	2380	1	5100
CO	1-hour	1090	269042	3839241	1587	2000	NA
	8-hour	375	267464	3838772	237	500	NA
SO_2	3-hour	14.93	267434	3838772	253	25	NA
	24-hour	4. 37	267464	3838772	235	5	NA
	Annual	0.4	268342	3840841	2380	1	NA
PM_{10}	24-hour	20.8[a]	267464	3838772	235	5	6072
	Annual	2.3	268242	3840841	2351	1	4861
Lead	Quarterly	0.0004	268342	3840841	2380	--	0.0044

[a] High second high value

Table 14. PSD Class II Increment and NAAQS Analysis

Pollutant	Averaging Period	Modeled Impact ($\mu g/m^3$)	PSD Increment ($\mu g/m^3$)	Background Conc ($\mu g/m^3$)	Total Concentration ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)	UTMX (m)	UTMY (m)
NO_X	Annual	2.53	25	20	22.53	100	268342	3840841
PM_{10}	24-hour	20.8	30	56.9	77.7	150	267464	3838772
PM_{10}	Annual	3.14	17	19.8	22.94	50	266542	3837441

Table 15. Results of Modeling at Sensitive Receptors for Big Sandy

Location	3-hr SO_2	24-hr SO_2	Annual NO_X	24-hr PM_{10}	Annual PM_{10}
Residence #1	0.4	0.1	0.03	0.5	0.03
Residence #2	0.4	0.1	.03	0.5	0.03
Residence #3	0.4	0.1	.02	0.2	0.02
Wikieup Golf Course	0.5	0.1	.02	0.2	0.02
Wikieup School	0.4	0.1	.02	0.2	0.02
Wikieup Trading Post	0.4	0.1	.02	0.2	0.02
Wikieup Subway Restaurant	0.5	0.1	.01	0.1	0.01
PSD Class II Increment	512	91	25	30	17

* Concentrations in ug/m^3

ADEQ had requested modeling analyses for 7 sensitive receptors in the project area. The maximum modeled impacts at these receptors are presented in Table 15, and are less than the PSD Class II increment levels.

Class I PSD increment results are presented in Table 16. The Federal Land Manager (FLM) will provide comments on the Class I analysis during the public comment period.

Table 16. PSD Class I Increment Analysis

Location	Pollutant	Averaging Period	ISCST3 Results	CALPUFF Results	PSD Class I Increment
Grand Canyon	SO_2	3-hr	N/A		25
		24-hr	N/A		5
		Annual	N/A		2
	PM_{10}	24-hr	N/A		8
		Annual	N/A		4
Sycamore Canyon	SO_2	3-hr	N/A		25
		24-hr	N/A		5
		Annual	N/A		2
	PM_{10}	24-hr	N/A		8
		Annual	N/A		4

c. Comparison with AAAQGs

Modeling was performed to determine if the source would exceed the AAAQGs for air toxics of concern. The applicant modeled emissions of these air toxics. This modeling used the same dispersion model (ISCPRIME), meteorological data, building downwash, and basic model parameters and assumptions used in the criteria pollutant modeling. Concentrations were modeled for the process area and ambient air, according to Department policy.

Table 17 presents the results of both short term and the annual AAAQG analysis. The modeling demonstrates that maximum predicted concentrations of all air toxics are less than the AAAQG values. The maximum annual impact is for formaldehyde, with impacts at 72% of the AAAQG. The maximum short term impact is for the 1-hour ammonia concentration, at 80% of the AAAQG.

B. Additional Impacts Analysis

1. Growth Analysis

The applicant proposes that approximately 25 permanent new positions will be needed for operation of the new facility. Therefore, the potential of additional industrial, commercial, and residential growth from this facility will be limited.

Increases in air emissions from this population influx are primarily a result of the increase in vehicle exhaust from the limited increase in traffic flow. The existing traffic flow on Highway 93 will not be significantly affected by this change. Therefore, the applicant estimates that no significant growth-related air quality impacts will occur. The department concurs.

2. Soils and Vegetation Impacts Analysis

A.A.C. R18-2-407.I.1 requires that the PSD permit application include an analysis of the impacts that emissions from proposed facility and from secondary growth will have on soils and vegetation. The applicant was unable to identify any specific sensitive soil and vegetation resources in the project vicinity. If the maximum predicted concentrations are compared to the screening levels found in the EPA document, "A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals", EPA 1980), none of the screening levels are remotely approached in magnitude. Therefore, the results indicate that the project will not adversely impact soils and vegetation in the area.

Table 17. Big Sandy Comparison to AAAQG for Compounds with Significant Emissions

HAP	Averaging Time	AAAQG (mg/m³)	Emission Rate (g/s)	Emission Rate (lbs/yr)	Predicted Max. Concentration	Percent of AAAQG
1,3-Butadiene	1-hour	5.00	3.87E-05		3.0E-03	0.06%
	24-hour	1.30	3.87E-05		5.4E-04	0.04%
	Annual	0.0063		3	3.5E-05	0.56%
Acetaldehyde	1-hour	630	3.89E-04		0.31	0.05%
	24-hour	170	3.89E-04		0.05	0.03%
	Annual	0.45		253	0.003	0.7%
Acrolein	1-hour	6.3	5.77E-04		0.048	0.8%
	24-hour	2	5.77E-04		0.008	0.4%
Ammonia	1-hour	230	2.378		184.6	80.2%
	24-hour	140	2.3788		25.2	18.0%
Benzene	1-hour	170	1.13E-03		0.094	< 0.01%
	24-hour	44	1.13E-03		0.016	0.04%
	Annual	0.12		76	.001	0.83%
Formaldehyde	1-hour	25	6.79E-02		5.67	22.7%
	24-hour	16	6.79E-02		0.94	5.88%
	Annual	0.076		4572	0.058	76.3%
Naphthalene	1-hour	630	1.17E-04		.01	< 0.01%
	24-hour	400	1.17E-04		0.002	<0.01%
Propylene Oxide	1-hour	370	2.61E-03		0.22	0.06%
	24-hour	98	2.61E-03		0.04	0.04%
	Annual	.27		181	0.002	0.74%
Toluene	1-hour	4400	1.17E-02		0.98	<0.01%
	24-hour	3000	1.17E-02		0.16	<0.01%
Xylene	1-hour	5400	5.77E-03		0.5	<0.01%
	24-hour	3500	5.77E-03		0.08	<0.01%

3. *Visibility Impacts Analysis*

A.A.C. R18-2-407.I.1 and R18-2-410 require that the PSD permit application include an analysis of the impacts that emissions from proposed facility and from secondary growth will have on visibility. This requirement is separate from any Class I visibility impact analysis. The visibility analysis was conducted for nearby special Class II areas, including 9 Bureau of Land Management (BLM) Wilderness areas, as requested by the FLM. The FLM will provide comments on these analysis during the public comment period.

4. *Class I Area Impacts Analysis*

Comments from the FLM will be provided during the public comment period.

5. *Conclusions*

The applicant has adequately demonstrated compliance with the NAAQS and PSD increments. None of the 23 air toxics evaluated were predicted to have impacts above the AAAQG.

The Class I analyses will be summarized upon receiving comments from the FLM.

IX. INSIGNIFICANT ACTIVITIES

No.	POTENTIAL EMISSION POINTS CLASSIFIED AS "INSIGNIFICANT ACTIVITIES" PURSUANT TO A.A.C. R18-2-101.54
1	Landscaping, building maintenance, janitorial activities
2	Building Air Conditioning Units, including portable air conditioning units and the exhaust vents from air conditioning equipment
3	Turbine Compartment Ventilation Exhaust Vents
4	Sanitary Sewer Vents
5	Compressed Air Systems
6	Turbine Lube Oil Vapor Extractors and Lube Oil Mist Eliminator Vents
7	Steam Drum Safety Relief Valve Vents
8	Emergency Diesel Fire Pump and Emergency Generator Fuel Storage Tank
9	Sulfuric Acid Storage Tank Vents
10	Various Steam Release Vents
11	Welding Equipment
12	Lab Hood Vents
13	Water Wash System Storage Tank Vents
14	Neutralization Basin
15	Sodium Hypochlorite Storage Tank
16	Hydrazine Storage Tank Vent
17	Fuel Purge Vents
18	Oil/Water Separator Waste Oil Collection Tank Vents
19	Sodium Hydroxide Storage Tank Vent
20	Condenser Vacuum Pump Vents

X. LIST OF ABBREVIATIONS

AAAQG	Arizona Ambient Air Quality Guideline
A.A.C.	Arizona Administrative Code
ADEQ	Arizona Department of Environmental Quality
AQRV	Air Quality Related Value
BACT	Best Available Control Technology
BLM	Bureau of Land Management
CAM	Continuous Assurance Monitoring
CEMS	Continuous Emission Monitoring System
CFR	Code of Federal Regulations
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CTG	Combustion Turbine Generator
DEM	Digital Elevation Model
DLN	Dry Low-NO_x
dscf	Dry Standard Cubic Foot
EPA	Environmental Protection Agency
^oF	Degrees Fahrenheit
FLM	Federal Land Manager
GEP	Good Engineering Practice
H_2	Hydrogen
H_2O	Water
HHV	Higher Heating Value
HRSG	Heat Recovery Steam Generator
hp	Horsepower
ISO	International Standard Operation
lb/hr	Pound per Hour
$\mu g/m^3$	Microgram per Cubic Meter
MMBtu/hr	Million British Thermal Units per Hour
MW	Megawatt
NAAQS	National Ambient Air Quality Standard
N_2	Nitrogen
NH_3	Ammonia
NO	Nitrogen Oxide
NO_x	Nitrogen Oxides

NO_2 . . . . Nitrogen Dioxide
NSPS . . . . New Source Performance Standard
NSR . . . . New Source Review
O_2 . . . . Oxygen
O_3 . . . . Ozone
Pb . . . . Lead
PM . . . . Particulate Matter
PM_{10} . . . . Particulate Matter Nominally less than 10 Micrometers
ppm . . . . Parts per Million
ppmvd . . . . Parts per Million by Dry Volume
PSD . . . . Prevention of Significant Deterioration
PTE . . . . Potential-to-Emit
RBLC . . . . RACT/BACT/LAER Clearinghouse
SCR . . . . Selective Catalytic Reduction
SIA . . . . Significant Impact Area
SIL . . . . Significant Impact Level
SNCR . . . . Selective Non-Catalytic Reduction
SO_2 . . . . Sulfur Dioxide
SO_3 . . . . Sulfur Trioxide
STG . . . . Steam Turbine Generator
TDS . . . . Total Dissolved Solids
TPY . . . . Ton per Year
TSP . . . . Total Suspended Particulates
USGS . . . . United States Geological Services
VOC . . . . Volatile Organic Compound